Standby Rates are Rates

Douglas Jester, 5 Lakes Energy

5 Lakes Energy’s Interest in Standby Rates

- Cost-effective Implementation of the Clean Power Plan
  - Increased use of renewables
  - Increased use of cogeneration
- Modernizing rates
  - Price signals to customers
  - Price signals to generators
  - Price signals to policy makers
- Accelerate innovation through market access for advanced energy technologies and companies
- Michigan economic development
  - Affordable rates
  - Supply chain development
- All technologies, but especially
  - Solar
  - Cogeneration

Basic Premises

- Rates for customers with self-service or distributed generation should be non-discriminatory
- Deficiencies when applying general rates to customers with self-service or distributed generation are deficiencies in the general rates
- Subsidies occur when rates are less than the ***marginal*** cost of service, not when allocated costs are shifted

Conclusions

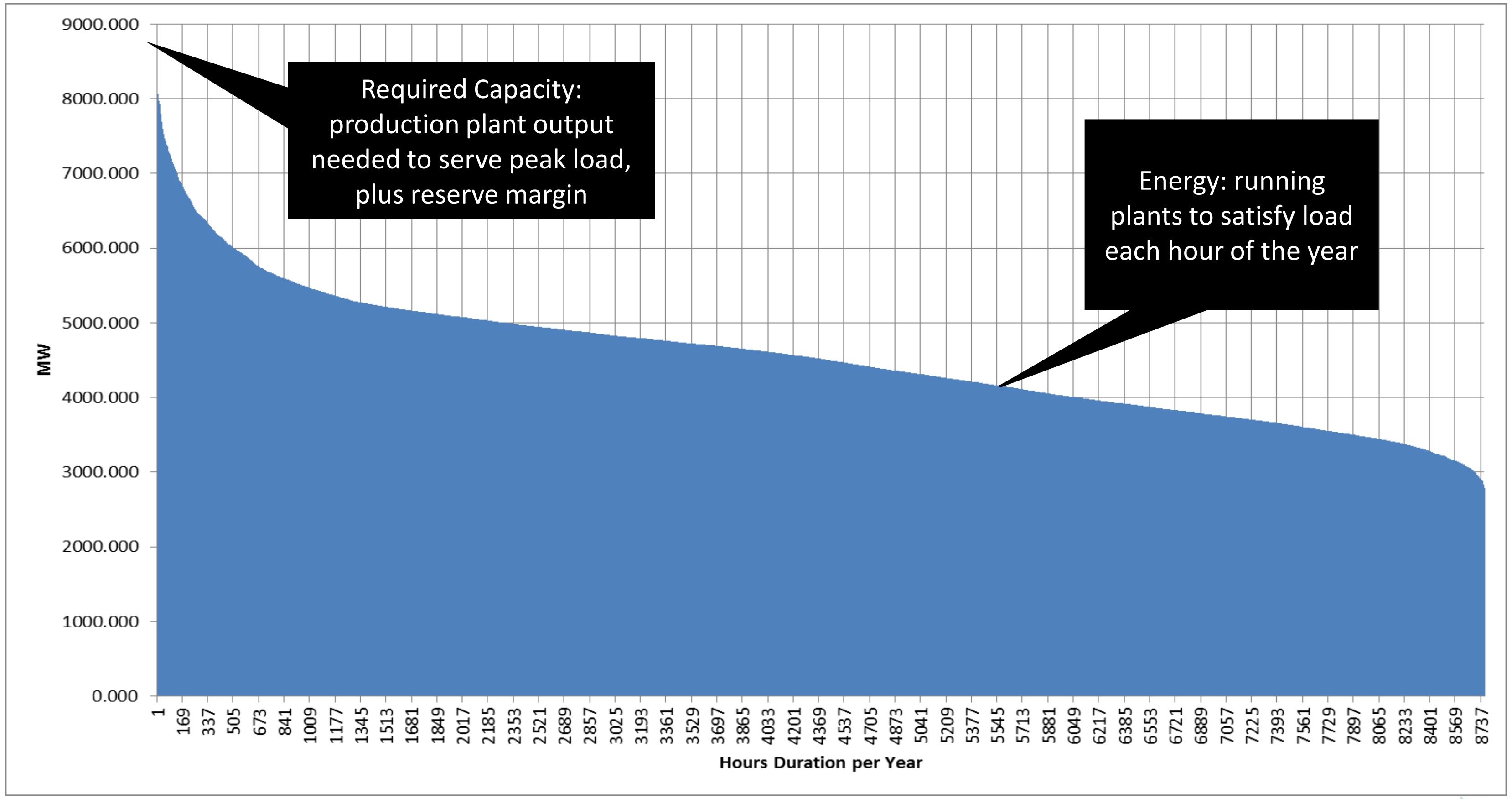
- Production and transmission costs should be allocated to individual customers by time-of-use with critical peak pricing
- Coincident peak cost allocation should be CONE plus reserve margin; other production plant costs should be allocated to energy
- Distribution costs should be allocated to customer inflow

TOU with CPP is consistent with IRP

- Integrated Resource Planning is the standard practice for deciding production portfolio, hence cost causation.
- Costs of an optimal portfolio are fully recovered by marginal cost pricing.
- For an optimal portfolio, marginal costs of non-peak load are locational marginal price and marginal costs of peak load are locational marginal price PLUS CONE
- Charging CONE for peak load suppresses demand and equilibrium is CPP

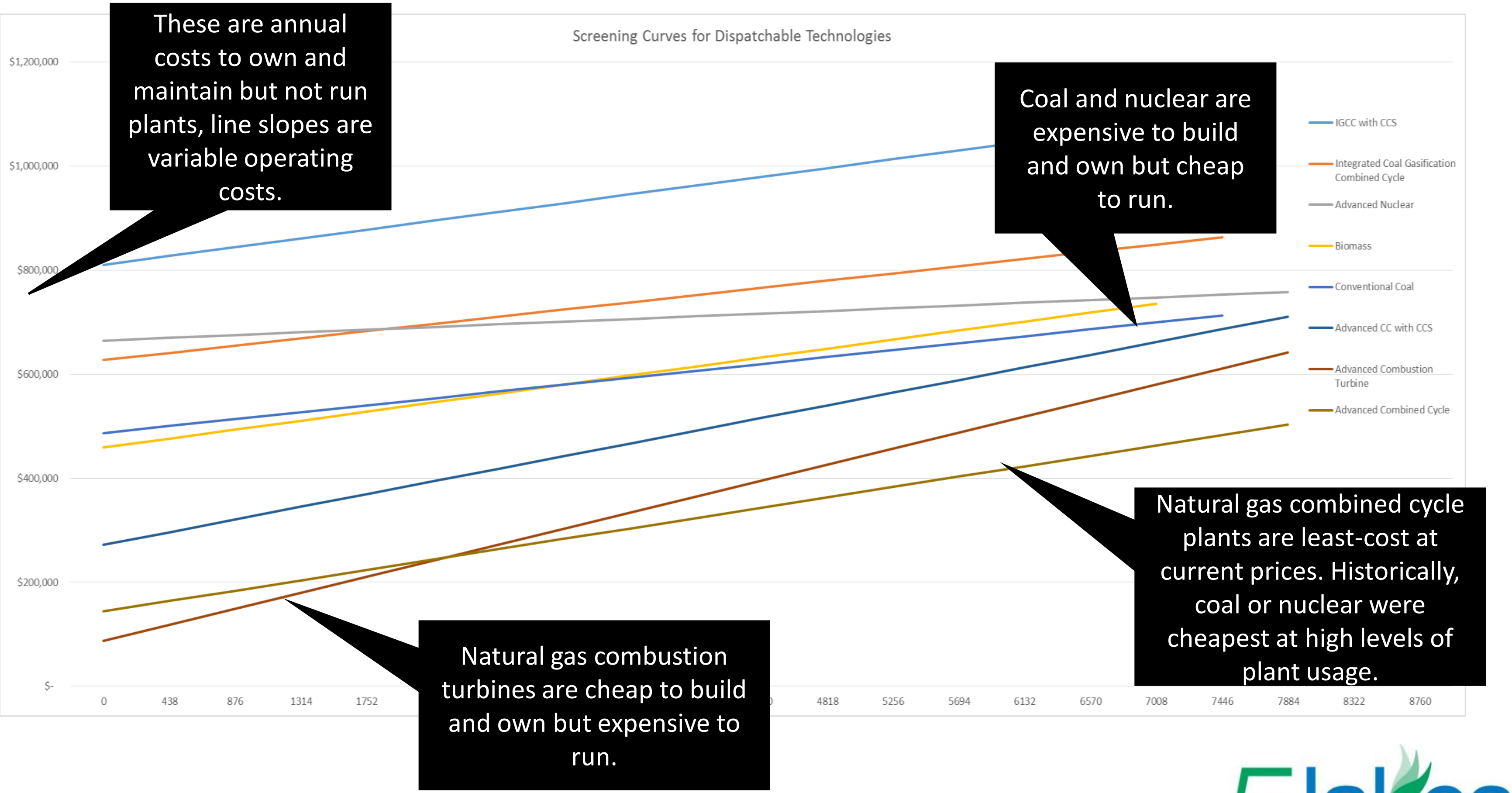
Key IRP Concepts: Load Duration Curve

Ordering the hours by load instead of time produces a load duration curve. This curve shows the number of hours of the year that load exceeds any given amount. Clearly some capacity will only be used part of the time.



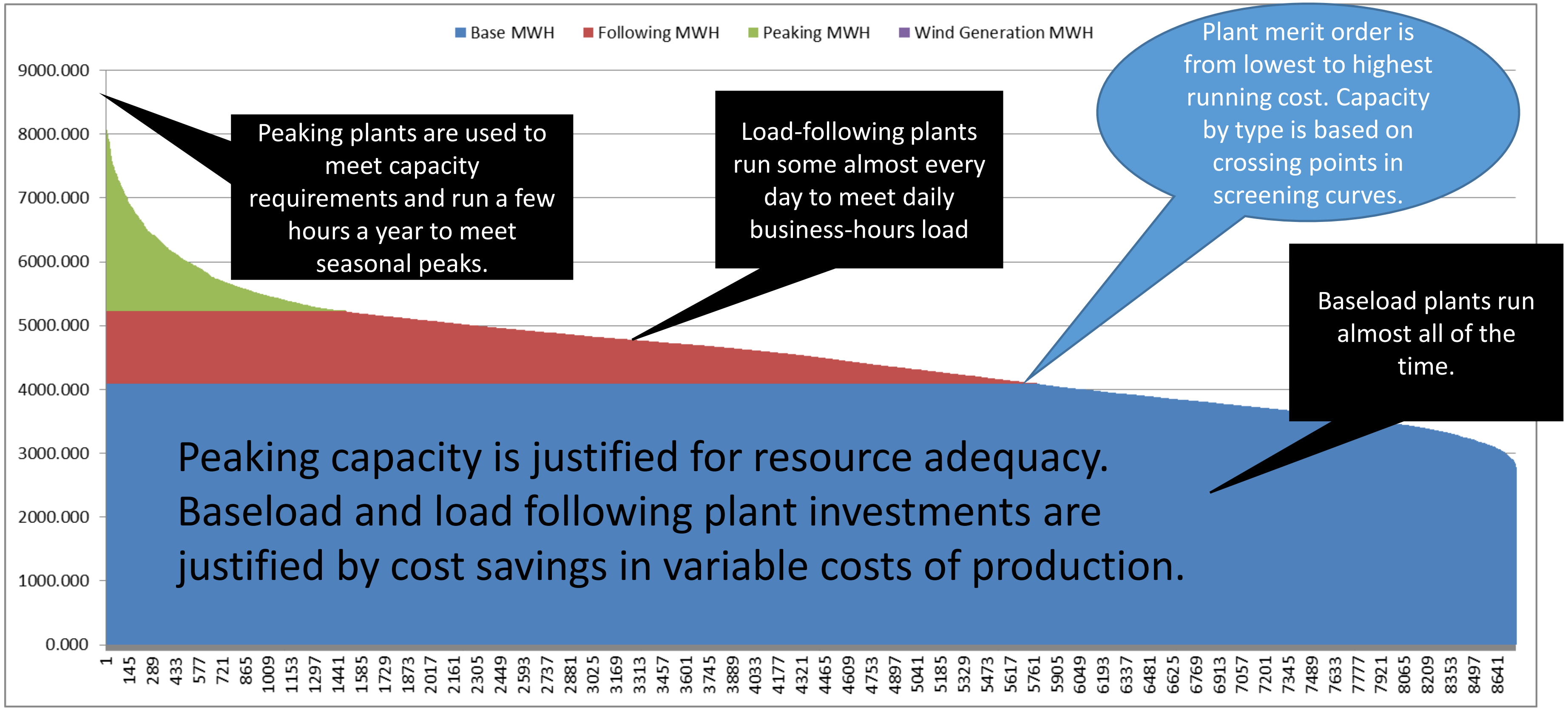
Key IRP Concepts: Technology Screening Curves

Technology screening curves show the cost per unit capacity to own and operate each type of plant varying number of hours per year. The least-cost portfolio uses the technologies that form the lower envelope.



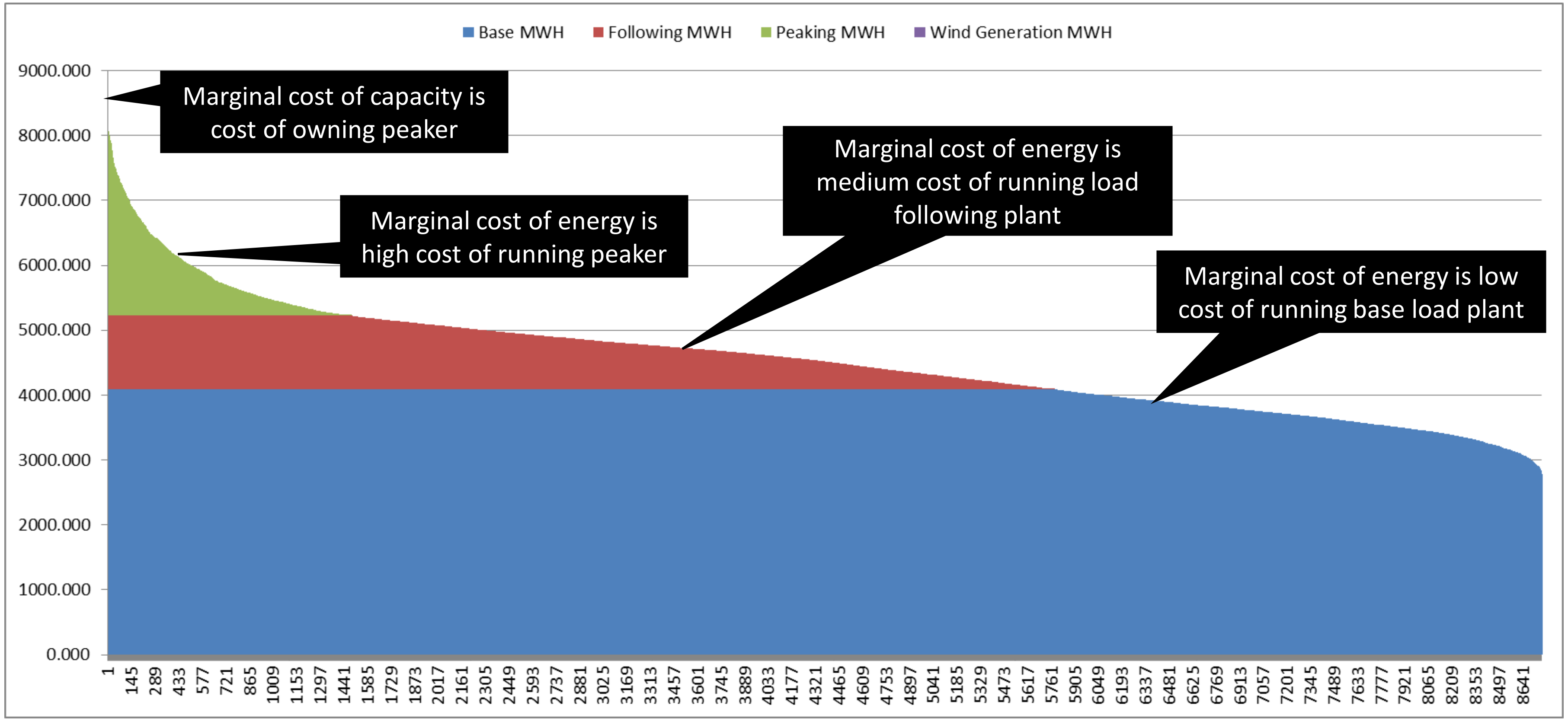
Key IRP Concepts: Optimum Generation Portfolio

Combining the ideas behind the load duration curve and technology screening curves, we find the traditional optimum generation portfolio of peakers, load-following, and base load plants.



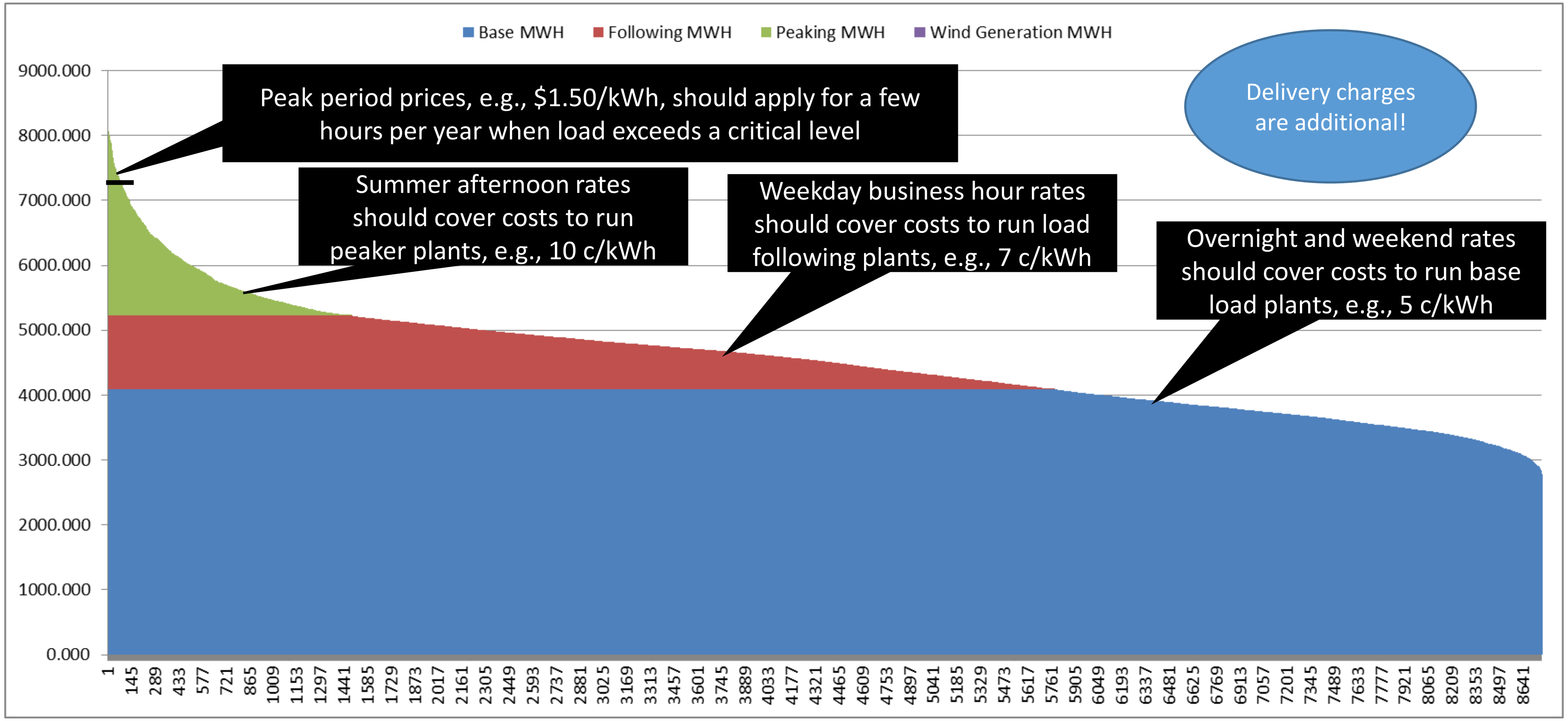
Using an IRP to Judge Whether Rates are Reasonable

The cost of a generation portfolio can be found by adding up various cost elements. The cost of a least-cost portfolio will also equal the value found by adding up peak load times the cost of owning peaking plants plus the amount of power used at each time multiplied by the cost per unit power of running the marginal plant. The difference is an inefficiency.



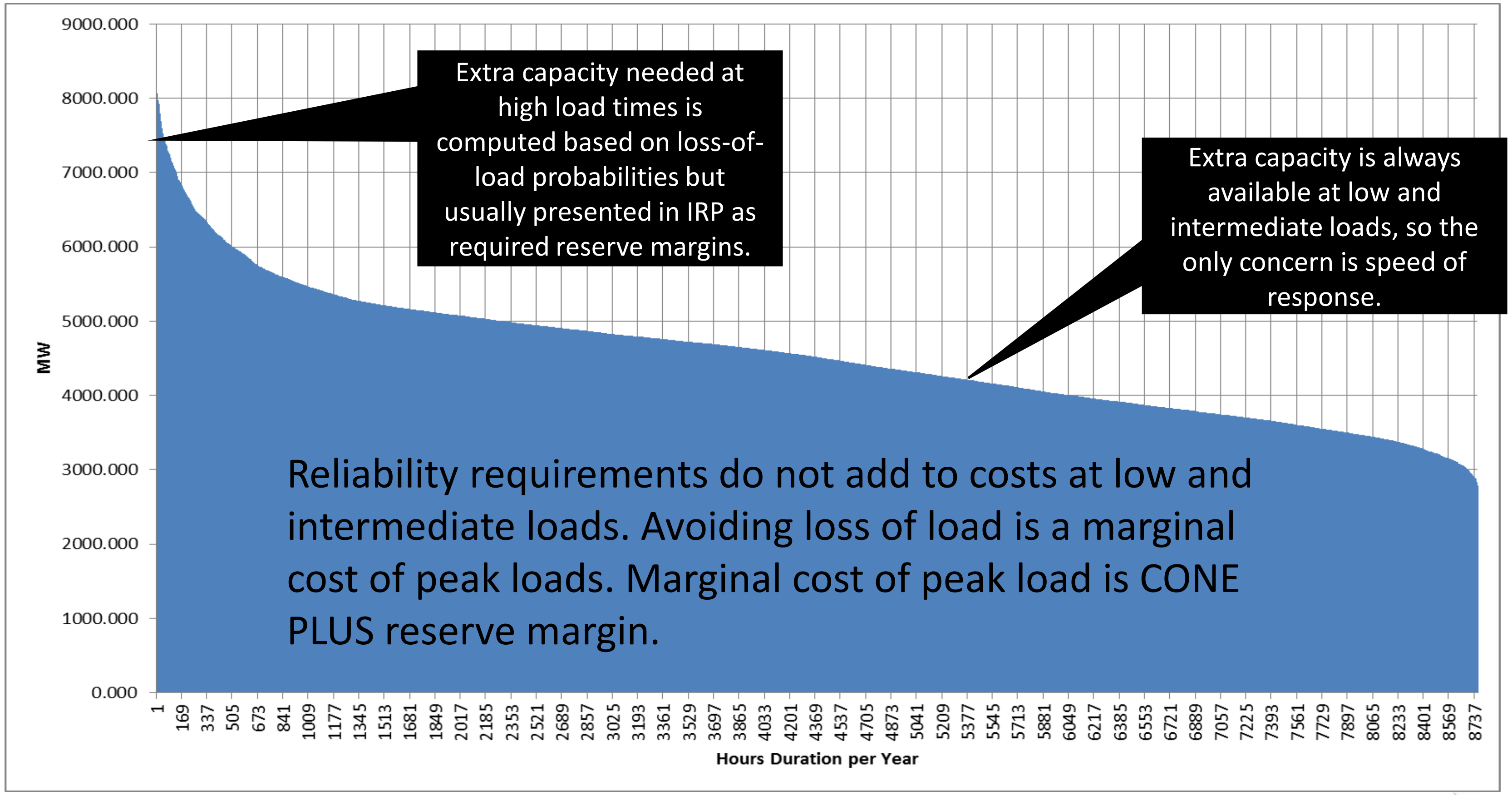
Cost Allocation and Rate Design Consistent with an IRP

Rates are based on allocating costs to customer classes, then converting those to unit prices. These are often fairly arbitrary and fail to inform customers about the actual cost of power they use. Dynamic rates, that vary by the hour, would be most efficient but time-of-use rates with peak-period pricing are almost as good.



Resource Adequacy and Reliability in an IRP

Most outages are grid failures, not supply problems. Resource adequacy requires sufficient generation reserve or demand responsiveness to deal with plant forced outages or unexpectedly high loads.



TOU with CPP provides better incentives

- Flat rates fail to signal when power is cheap or expensive, so fail to guide customers to optimal scheduling of power use
- Demand charges incent flattening the customer's load, not flattening system load. The results can be wasteful activity or even perverse load shifting.
- Interruptibility is inferior to CPP
  - Utility is not incented to interrupt, but to carry excess capacity
  - Buy through rates underprice capacity
  - Discounted rates for interruptible customers invite gaming the system
  - Cost of interruption is time-specific and CPP allows the customer to decide
- CPP is better than a reservation charge
  - Customer is incented to reduce demand during generation outage if and only if utility capacity is in short supply

Distribution System Cost Allocation

- In context of universal service, marginal costs of customer interconnection are limited to
  - Customer service, metering and billing, service drop, and a share of service transformer
- For most customers, all other distribution costs are shared and joint
  - For customers with unusual distribution costs, utilities require contribution in aid of construction
- Most distribution system costs are not drive by demand but by geography
- Distribution grid is necessary for distribution of all power, not just peak power
- Optimal allocation of distribution cost is approximately a % markup on power supply costs (in context of TOU with CPP).
- % markup charges more at peak load times, less at low load times so approximately captures effects of time-specific load on line losses, system wear, and capacity requirements

Distribution Cost Allocation to Customers with Self-Service or Distributed Generation

- New load is not absolved from distribution charges. It dilutes distribution charges to continuing load.
- Symmetrically, load reductions should not be burdened with charges for “pretend” load. Instead distribution costs should be concentrated on remaining load.
  - We don’t charge former customers who go out of business for lost load
  - We don’t charge residential customers for lost load when children leave for college
  - We don’t charge for lost load when customers substitute more energy efficiency equipment
  - We shouldn’t charge for lost load when customers generate for self service
- Customers with self-service or distributed generation should pay for distribution based on the power delivered to them.

Inflow – Outflow provides better incentives

- Inflow-outflow rate design charges the customer for inflow at retail, including both power supply and distribution, and credits outflow at power supply (retail less distribution).
- Method is consistent with the treatment of load changes for an individual customer due to all other causes
- Avoided cost of distribution for self-service is a cost shift but not a subsidy; charges customer in approximate proportion to value received from gird services
- Does not incent grid defection; puts distribution cost of inflow against cost of storage

Recommendations

1. Eliminate standby, supplementary, and other charges in favor of better rate design
2. Place customers with self-service or distributed generation in tariffs with time-of-use and critical peak pricing for power
    a) Critical peak pricing should recover CONE plus reserve margin on planned capacity
3. Allocate cost of service and design rates for distribution based on inflow-outflow.
    a) Distribution should be percentage markup on power supply costs rather than fixed price per kWh
4. Net metering at flat retail is “rough justice”. Combining (2) and (3) produces similar net numbers. (2) and (3) better align incentives.